

# Electricity Report

14 to 20 July 2013



## Introduction

The AER is required to publish the reasons for significant variations between forecast and actual price and is responsible for monitoring activity and behaviour in the National Electricity Market. The Electricity Report forms an important part of this work. The report contains information on significant price variations, movements in the contract market, together with analysis of spot market outcomes and rebidding behaviour. By monitoring activity in these markets, the AER is able to keep up to date with market conditions and identify compliance issues.

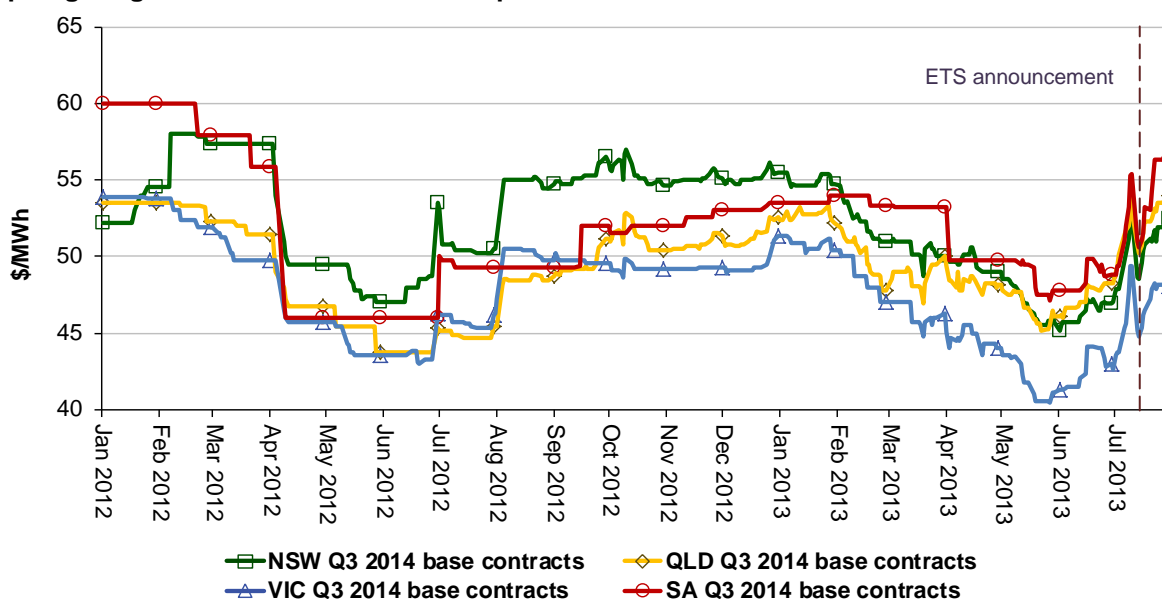
## Weekly spotlight

On 1 July 2012 the Australian Government introduced a carbon price as part of its Clean Energy Future Plan. Initially the carbon price was initially set at \$23 per tonne of carbon dioxide equivalent emissions for the first year of the scheme, with increases in line with the CPI for the second and third years, with a floating price to be set under an Emissions Trading Scheme (ETS) from 1 July 2015. However, on 15 July this year, the Australian Government announced that it would fast track the introduction of a floating carbon price to 1 July 2014.

Prior to this, in August 2012, the Australian Government had announced the floor price originally scheduled to apply during the first three years of the ETS would be removed and instead would be linked to the European Union's ETS. The international carbon price is currently estimated to be \$6/tonne compared to Australia's 2013/14 fixed carbon price of \$24.15/tonne.

Quarter 3 2014 is the first quarter affected by the change in policy to bring forward the move to a floating carbon price. The price of Q3 2014 base contracts reflects the market's expectations of wholesale spot prices during that quarter.

### Spotlight figure: Q3 2014 Base contract prices



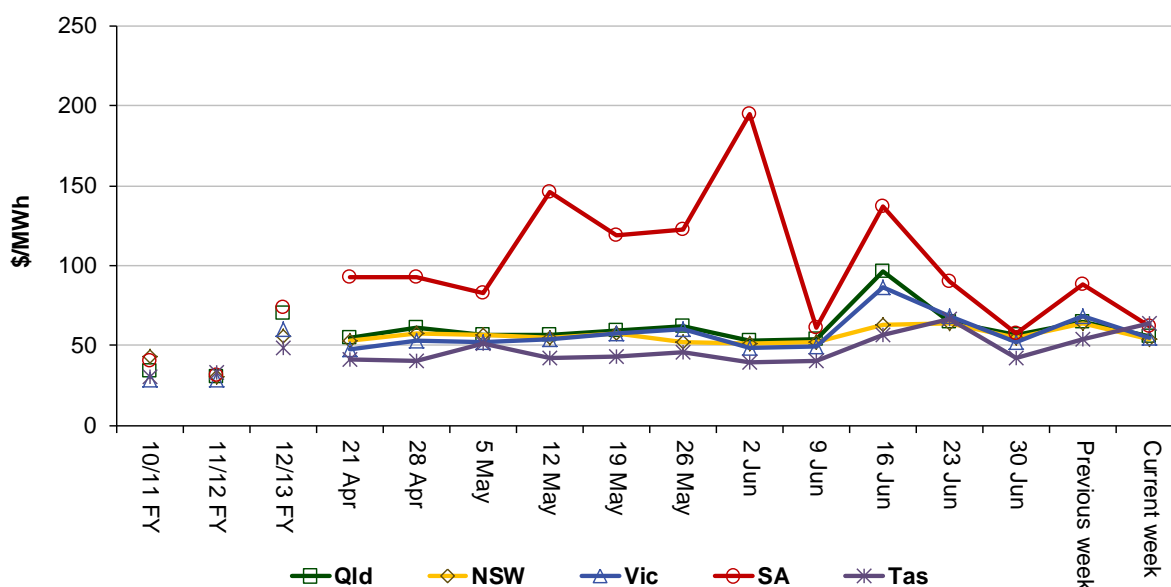
The weekly spotlight figure shows that there had been a gradual decline in the price of Q3 2014 base contracts from the beginning of this year, falling by around \$10/MWh to a low point of \$45/MWh for Queensland and NSW by the end of May. The price had then started moving back up towards \$55/MWh during June and July. Interestingly, (given the generation mix in the region) the Victorian Q3 2014 price has been tracking nearly \$5/MWh lower than other regions since April. On the day (15 July) of the Australian Government’s announcement of the early transition to an ETS, the price of Q3 2014 base contracts dropped by \$3-5/MWh across the regions, but has rebounded subsequently.

The Q3 2014 prices as at 19 July ranged from \$46.50/MWh for Victoria to \$53.20/MWh in South Australia. This compares to Q3 2013 base contract price range of \$57.20/MWh for New South Wales to \$71/MWh for South Australia.

## Spot market prices

Figure 1 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

**Figure 1: Volume weighted average spot price by region (\$/MWh)**



**Table 1: Volume weighted average spot prices by region (\$/MWh)**

Region	Qld	NSW	Vic	SA	Tas
<b>Current week</b>	56	54	55	62	64
<b>12-13 financial YTD</b>	64	68	81	87	62
<b>13-14 financial YTD</b>	59	58	59	70	53

Longer-term statistics tracking average spot market prices are available on the [AER website](#).

## Spot market price forecast variations

The AER is required under the National Electricity Rules to determine whether there is a significant variation between the forecast spot price published by the Australian Energy Market Operator (AEMO) and the actual spot price and, if there is a variation, state why the AER considers the significant price variation occurred. It is not unusual for there to be significant variations as demand forecasts vary and participants react to changing market conditions. A key focus is whether the actual

price differs significantly from the forecast price either four or 12 hours ahead. These timeframes have been chosen as indicative of the time frames within which different technology types may be able to commit (intermediate plant within four hours and slow start plant within 12 hours).

There were 41 (30-minute) trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2012 of 60 counts and the average in 2011 of 78. Reasons for the variations for this week are summarised in Table 2. Based on AER analysis, the table summarises (as a percentage) the number of times when the actual price differs significantly from the forecast price four or 12 hours ahead and the major reason for that variation. The reasons are classified as availability (which means that there is a change in the total quantity or price offered for generation), demand forecast inaccuracy, changes to network capability or as a combination of factors (when there is not one dominant reason). An instance where both four and 12 hour ahead forecasts differ significantly from the actual price will be counted as two variations.

**Table 2: Reasons for variations between forecast and actual prices**

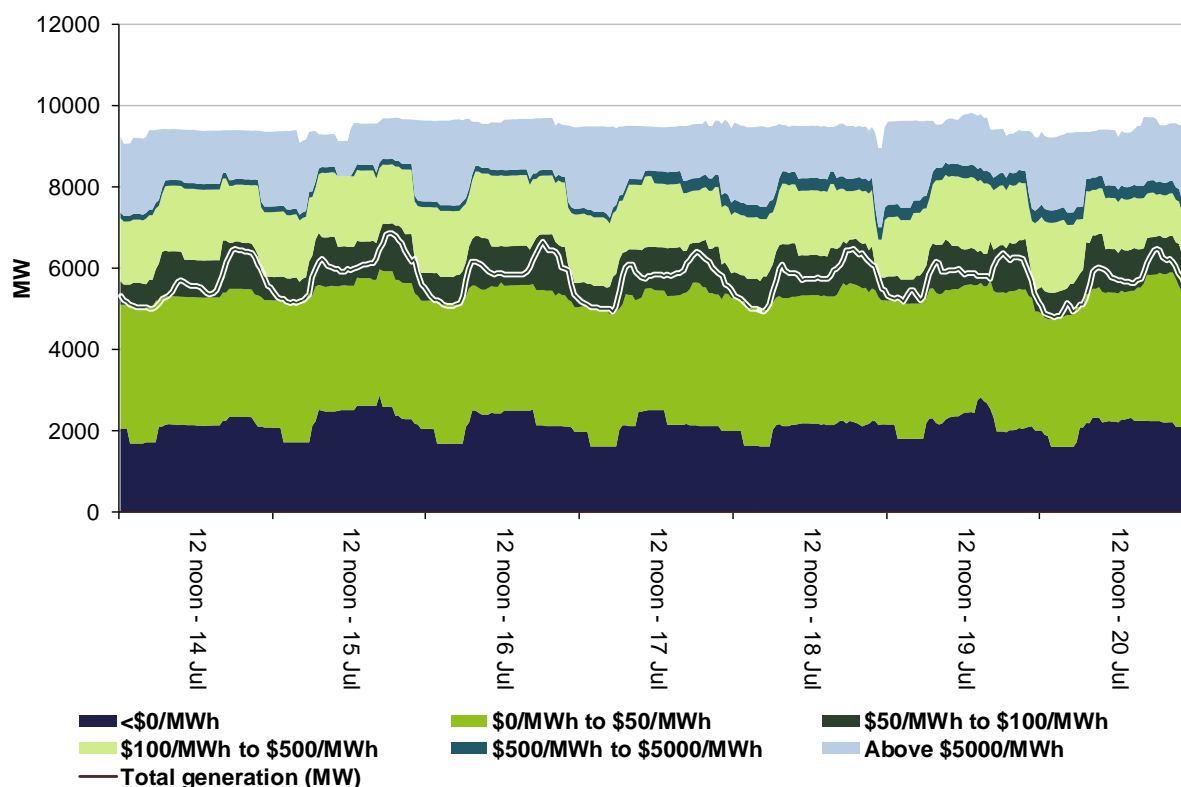
Reason for variation	Availability	Demand	Network	Combination
% of total above forecast	0	8	7	2
% of total below forecast	24	48	0	11

Note: Due to rounding, the total may not be exactly 100 per cent

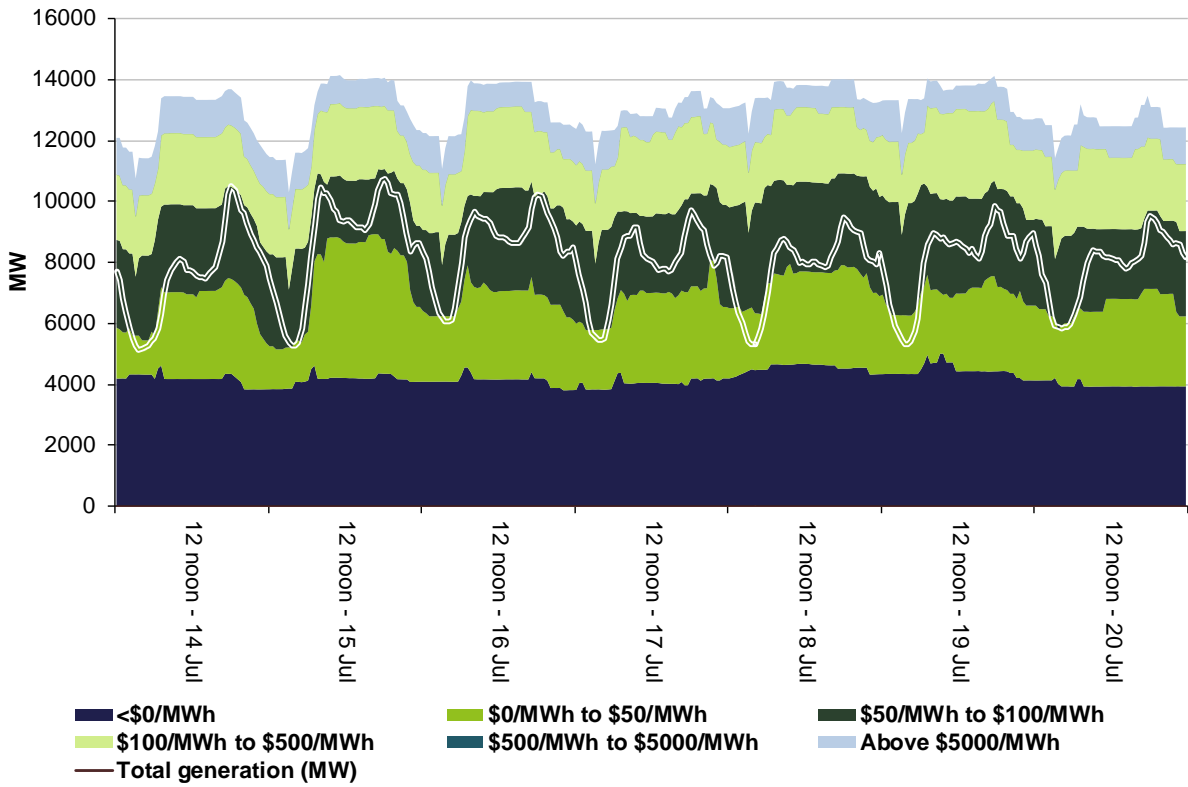
## Generation and bidding patterns

The AER reviews generator bidding as part of its market monitoring to better understand the drivers behind price variations. Figures 2 to 6 show, the total generation dispatched and the amounts of capacity offered within certain price bands for each 30 minute trading interval in each region.

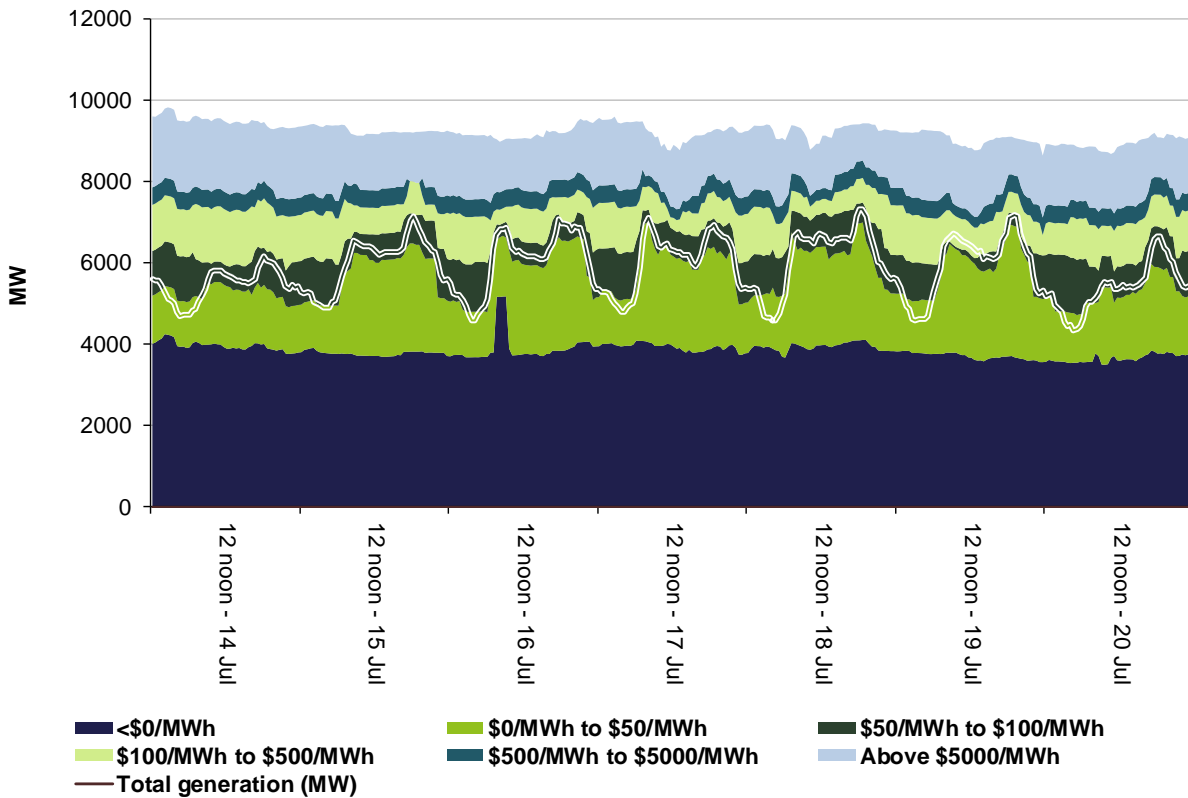
**Figure 2: Queensland generation and bidding patterns**



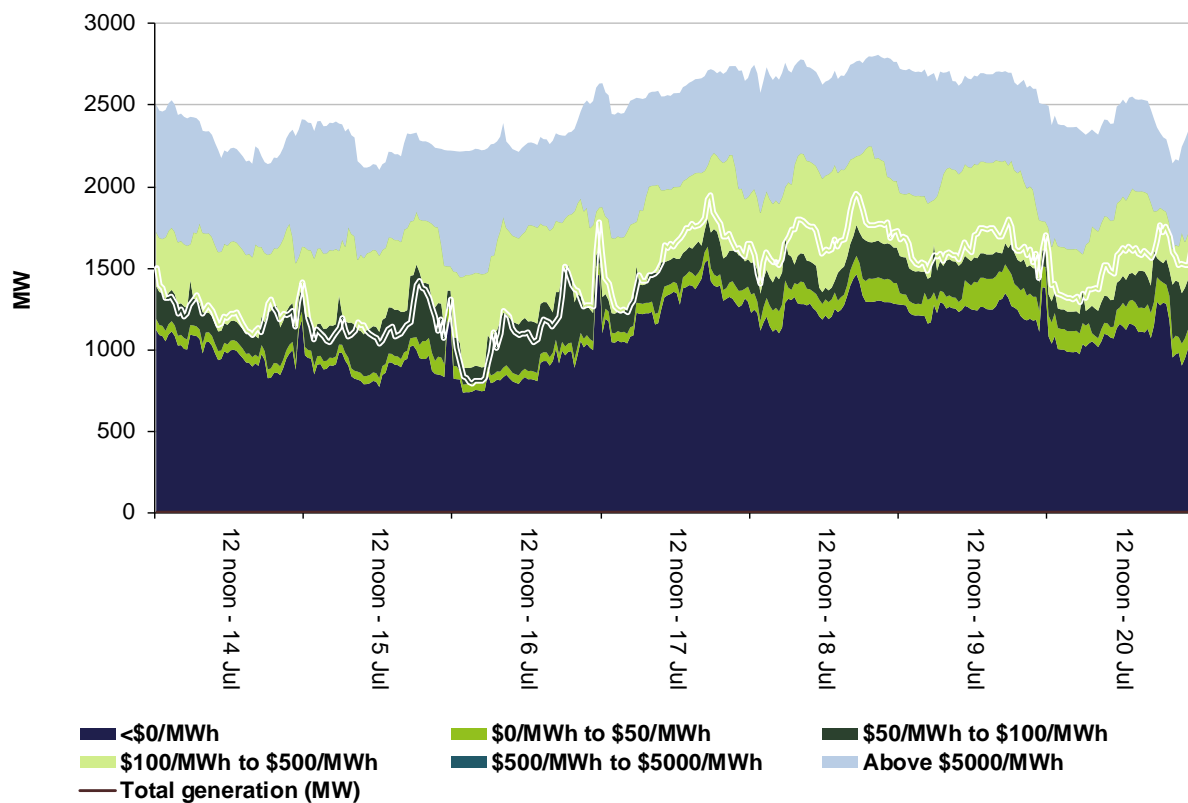
**Figure 3: New South Wales generation and bidding patterns**



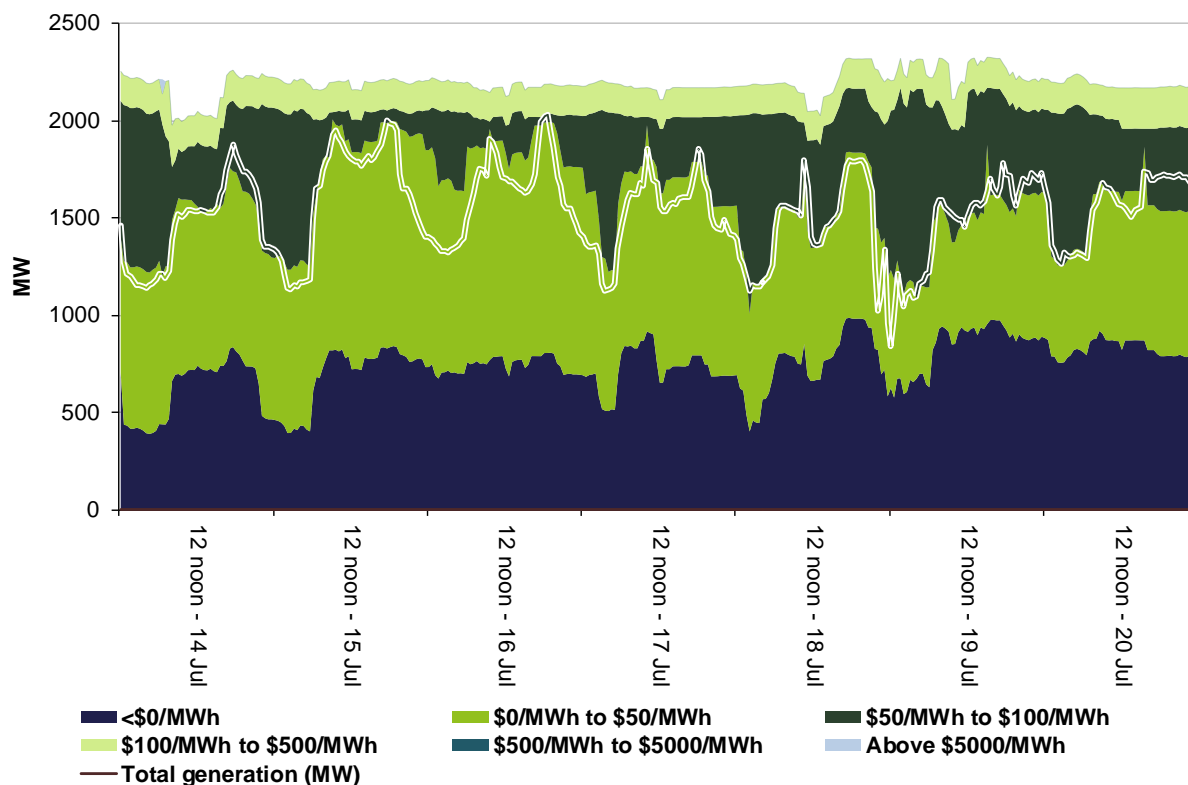
**Figure 4: Victoria generation and bidding patterns**



**Figure 5: South Australia generation and bidding patterns**



**Figure 6: Tasmania generation and bidding patterns**



## Frequency control ancillary services markets

Frequency control ancillary services (FCAS) are required to maintain the frequency of the power system within the frequency operating standards. Raise and lower regulation services are used to address small fluctuations in frequency, while raise and lower contingency services are used to address larger frequency deviations. There are six contingency services:

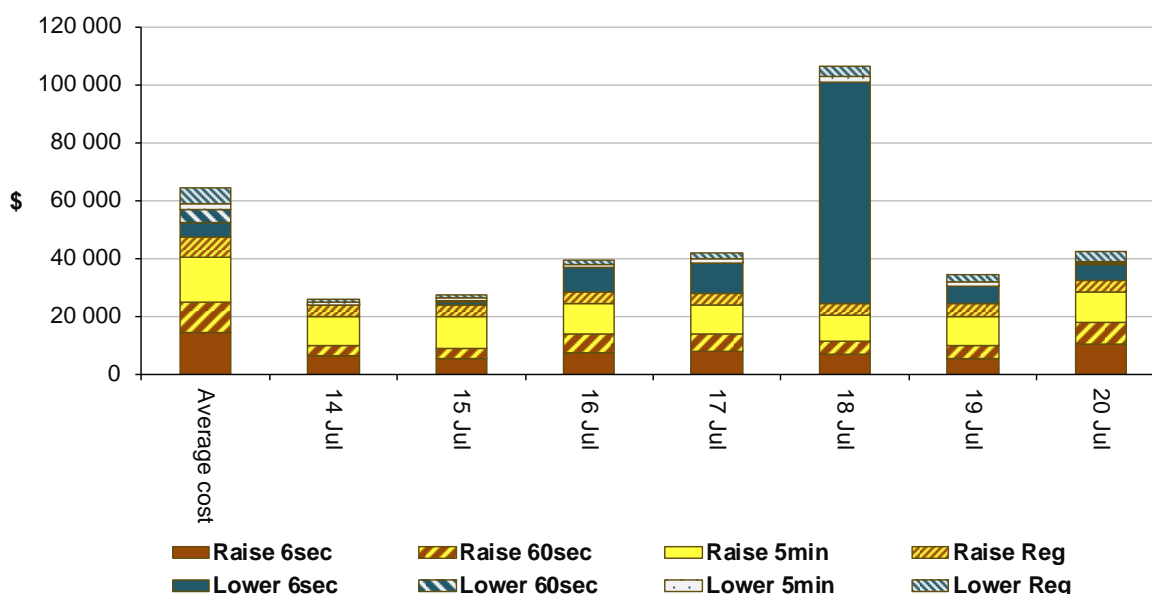
- *fast services*, which arrest a frequency deviation within the first 6 seconds of a contingent event (raise and lower 6 second)
- *slow services*, which stabilise frequency deviations within 60 seconds of the event (raise and lower 60 second)
- *delayed services*, which return the frequency to the normal operating band within 5 minutes (raise and lower 5 minute) at which time the five minute dispatch process will take effect.

The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was \$241 000, or less than one per cent of energy turnover on the mainland. In Tasmania (which requires dedicated services for much of the time) the total cost for the week was \$123 500 or less than one per cent of energy turnover in Tasmania. A majority of the cost (\$76 000) occurred on 18 July for Lower 6 second services when the loss of the double circuit Sheffield to George Town 220 kV lines was reclassified as a credible contingency due to lightning (see *Detailed market analysis of significant price events*). This saw around 300 MW of Tasmanian generation constrained down and precluded from providing FCAS. As a result the price for that service reached \$2247/MW at 11.40 pm.

Figure 7 shows the daily breakdown of costs for each service, as well as the average daily costs for the previous financial year.

**Figure 7: Daily frequency control ancillary service cost**



## Detailed market analysis of significant price events

We provide more detailed analysis of events where the spot price was greater than three times the average weekly price in a region and above \$250/MWh or was below -\$100/MWh.

There were three such occasions during this week, which occurred in Tasmania on Sunday 14 and Thursday 18 July. The tables below show actual Tasmanian price, demand and available capacity outcomes compared to those forecast 4 and 12 hour ahead.

**Table 3: Tasmania, Sunday 14 July**

10:00 PM	Actual	4 hr forecast	12 hr forecast
Price (\$/MWh)	1834.38	58.67	56.06
Demand (MW)	1167	1214	1189
Available capacity (MW)	2218	2195	2188

Conditions at the time saw demand and available capacity close to that forecast.

The high price was driven by network constraints in Tasmania. The constraint T>>T\_NIL\_BL\_EXP\_5F manages post contingent flows on the Hadspen to Georgetown 220 kV lines. The constraint affects all Tasmanian generation except for generation at Tamar Valley (which was offline) and forces exports to Victoria across Basslink.

An increase in flows across the Hadspen to Georgetown 220 kV lines from 9.40 pm caused the T>>T\_NIL\_BL\_EXP\_5F constraint to bind intermittently. When the constraint bound for the 10 pm dispatch interval, around 250 MW of Tasmanian generation was constrained down and exports to Victoria were reduced by 75 MW. Due to limited ramp rate capability (and generators trapped in FCAS) the five minute price reached \$10 607/MWh.

In response to the high price there was an apparent 45 MW demand side response from a Tasmanian industrial load and prices returned to previous levels

There was no significant rebidding.

**Table 4: Tasmania, Thursday 18 July**

10:00 PM	Actual	4 hr forecast	12 hr forecast
Price (\$/MWh)	2340.35	36.28	43.90
Demand (MW)	1052	1120	1142
Available capacity (MW)	2268	2258	2243
11:30 PM	Actual	4 hr forecast	12 hr forecast
Price (\$/MWh)	2209.02	36.28	44.30
Demand (MW)	919	975	1023
Available capacity (MW)	2200	2255	2202

Conditions at the time saw demand and available capacity close to that forecast.

At 9.35 pm AEMO reclassified the simultaneous loss of the Sheffield to George Town 220 kV lines as a credible contingency, due to lightning, and invoked a constraint. This constraint affects all generation in Tasmania except for generation at Tamar Valley (which was offline).

Between 9.35 pm and 9.40 pm the constraint reduced Tasmanian generation by around 330 MW but the changes were insufficient to meet the constraint requirements, resulting in the constraint violating for two dispatch intervals from 9.35 pm. The reduction in generation led to flows on Basslink changing from exports to Victoria to imports into Tasmania, crossing the no go-zone at 9.40 pm. As a result the 5 minute price reached \$832/MWh at 9.35 pm and the cap at 9.40 pm.

Prices returned to previous levels at 9.45 am when Basslink was able to import into Tasmania and an apparent 102 MW demand side response from an industrial load.

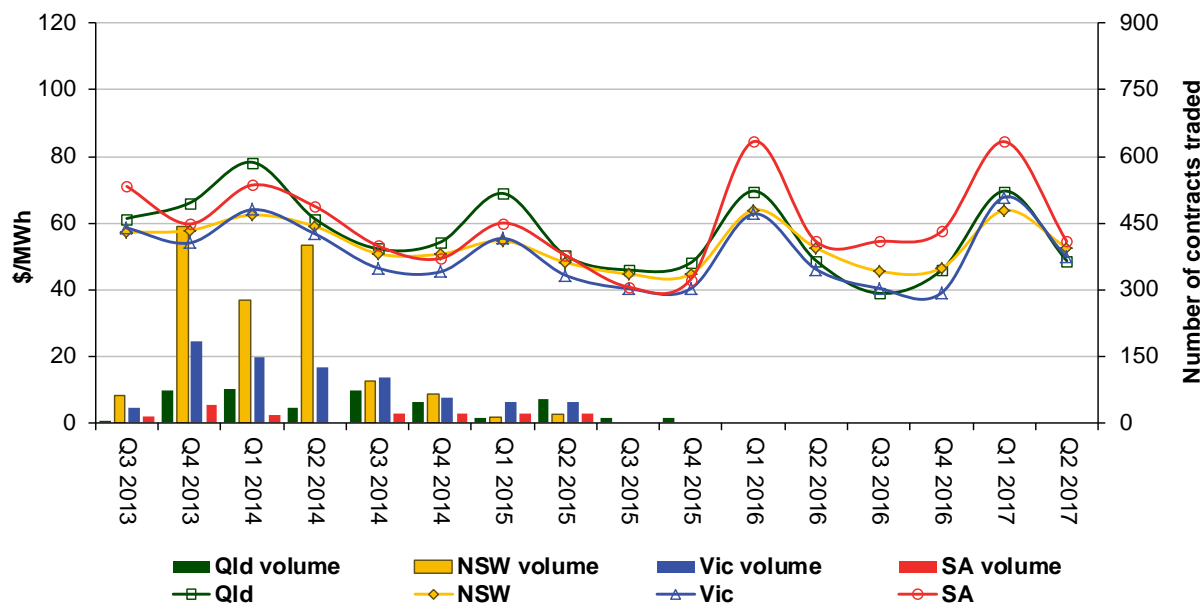
Further lightning saw the constraint re-invoked from 11.25 pm, again resulting in a number of generating units having their output reduced (by up to 285 MW from 11.30 pm). There was also a reduction in exports to Victoria to 74 MW (Basslink couldn't reduce further because it would enter the no-go zone) but the changes were insufficient to meet the constraint requirements, resulting in the constraint violating and the price reaching the cap at 11.30 pm.

There was no significant rebidding.

## Financial markets

Figure 8 shows for all mainland regions the price for base contracts (and total traded quantities for the week) for each quarter for the next four financial years.

**Figure 8: Quarterly base future prices Q3 2013 – Q2 2017**

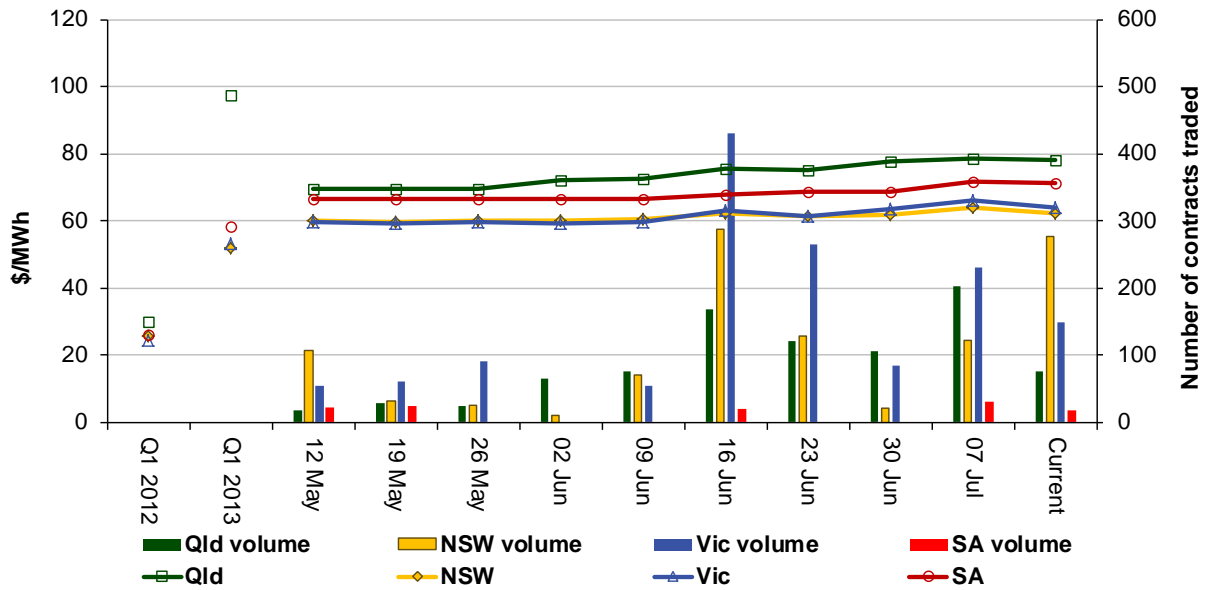


Source: [ASXEnergy.com.au](http://ASXEnergy.com.au)

Figure 9 shows how the price for each regional Quarter 1 2014 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing Quarter 1 2012 and Quarter 1 2013 prices are also shown.



**Figure 9: Price of Q1 2014 base contracts over the past 10 weeks (and the past 2 years)**



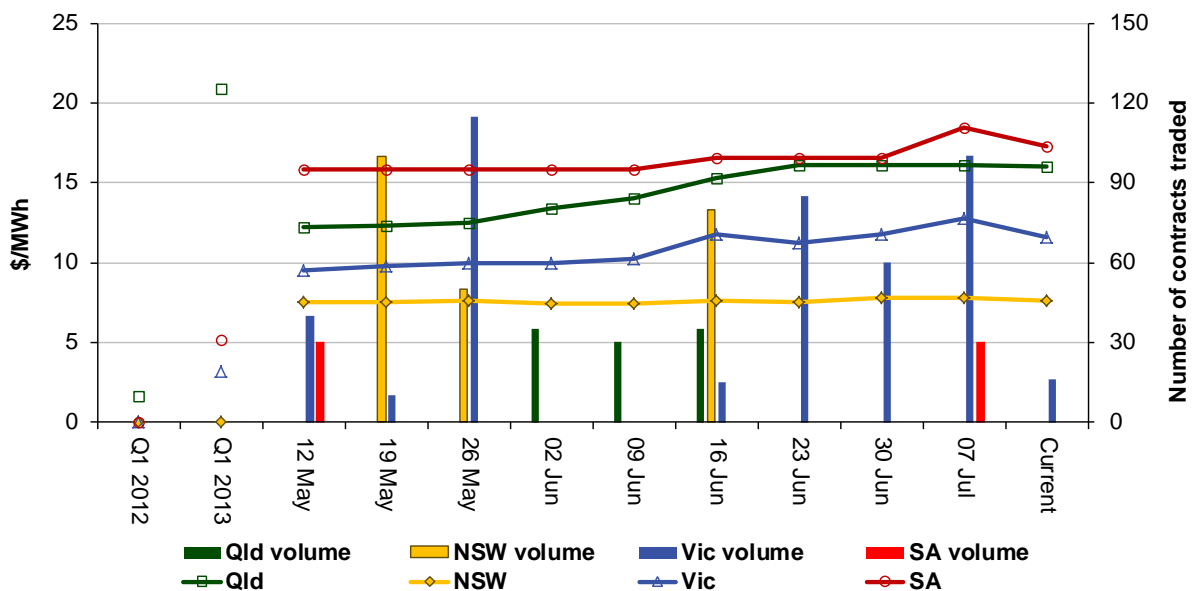
Note: Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for yearly periods 1 and 2 years prior to the current year

Source: [ASXEnergy.com.au](http://ASXEnergy.com.au)

Prices of other financial products (including longer-term price trends) are available in the [Performance of the Energy Sector](#) section of our website.

Figure 10 shows how the price for each regional Quarter 1 2014 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing Quarter 1 2012 and Quarter 1 2013 prices are also shown. The cap contracts limit exposure to extreme spot prices (above \$300/MWh) and is an indicator of the cost of risk management.

**Figure 10: Price of Q1 2014 cap contracts over the past 10 weeks (and the past 2 years)**



Source: [ASXEnergy.com.au](http://ASXEnergy.com.au)